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NSTAR Capital Project Ranking

Overview and Methodology Report

October 2003

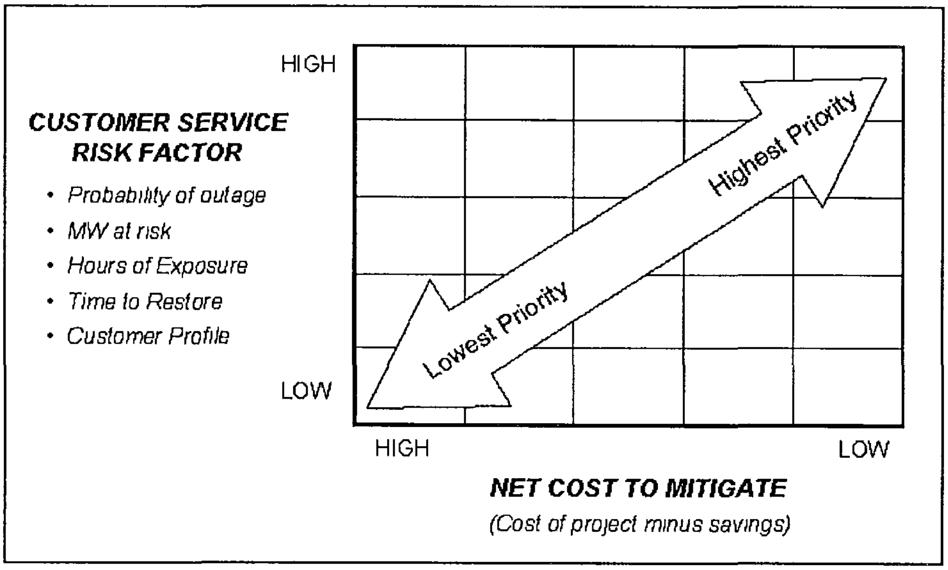
Capital Project Ranking Process Methodology

Overview

The capital project ranking process was initiated in late August of 2003 to allow the Engineering Organization to minimize risk and maximize value given a fixed amount of funding. It involves a probabilistic assessment of the expected energy at risk, which is a measure of the magnitude and duration of customer interruptions that are likely to occur in the next year. For capacity projects, this entails assessing the extent of overloads and the amount of load shedding that must occur to avoid damaging the infrastructure. For reliability projects, the measure focuses on the degree to which the project will reduce the frequency or duration of outages given the historical performance of the system.

In addition to assessing the amount of energy at risk the project will mitigate, the process also considers the estimated expenditures, as well as savings created as a result of the project, to create a cost-benefit analysis. Of interest is the amount of energy in kWh that can be mitigated by $1,000. An elementary overview of the factors is shown below.

Overview of Project Prioritization Factors



The advantage of this system is its ability to use objective measures to quantify the deficiencies that the projects will resolve. In the past, projects may have been justified based on a "large amount of load at risk", or "very poor reliability". With the new process, they are now justified on exactly how much load is at risk, how long the conditions may last, the probability of load loss, the customer outage hours, and other factors. This process creates a practical way to evaluate projects, which on the surface, appear to be equally beneficial.

Subjective considerations are used in the prioritization process as well. Although they are not given a numerical weight, they may allow justification based on merits other than the expected energy at risk. These measures include:

- Projects in communities that are investigating the feasibility of municipal electric departments
- Projects in communities with historically low MBIs (months between outages)
- Commitments made to the town or DTE
- Number of complaints received
- Effect of outages on customer (nuisance versus significant hardship)

The ranking strategy does not accommodate all types of projects, however. Some of these include OHSA-mandated modifications, transformer and load-tap changer monitoring systems and the purchase of spare equipment. In cases such as these, each project was evaluated separately based on its necessity and merits.

Introduction to Ranking Projects

Capital projects submitted for ranking can be divided into two main groups: capacity (including voltage support) and reliability. Each group is ranked differently, with special dispensation given to those capacity projects that will improve reliability, or vice versa. The calculations for each will result in an expected energy at risk (EAR) value in kVAh that is based on both the likelihood and consequences of an event.

Projects were selected using a variety of criterion. The two objective measures are the EAR benefit and the EAR/Net Project Cost. The EAR benefit is simply a difference of the EAR prior to project completion and after project completion. The EAR / Net Project Cost is used to gauge the amount of risk that can be mitigated for every $1000 spent to complete the project and saved as a result of the work. Subjective measures used in project selection are based on past customer experience, DTE or community commitments, and the performance trends of the affected town as a whole.

$$\text{EAR Benefit} = \text{EAR}_{\text{Prior to Project}} - \text{EAR}_{\text{Anticipated after Project Completion}}$$

$$\text{EAR Benefit / Net Project Cost}_{\$1000} = \text{EAR Benefit} \div (\text{Total Cost} - \text{5 Year Annual Savings})$$

Although the major component in deciding upon the final project set is based on EAR Benefit / Net Project Cost, there are certain projects that need special consideration based on the amount of risk or the high consequences if the work is not completed. Therefore, all subjective and objective measures will be considered.

For the 2004-2005 budget cycle, System Engineering, Distribution Technical Engineering, Substation Technical Engineering and System Planning submitted approximately 600 projects totaling nearly $300 million. From this list, the Engineering Organization selected the most critical and beneficial projects to be completed in 2004. The final selection will take place towards the end of 2004, when all carryover projects and their 2004 costs are identified. The following document explains what factors were used to compute the expected energy at risk benefit, as well as the criteria for assigning values to the subjective measures.

Capacity Projects

Capacity projects are generally submitted by either System Planning or System Engineering, and include the following:

- New substations
- Substation transformer upgrades or additions
- Transmission line upgrades
- DSS line upgrades
- Circuit upgrades
- Step-down transformer replacements
- Voltage support and regulation

If resolving the capacity problem will also improve reliability in a measurable way, the project can be run through the reliability EAR calculation model to determine additional benefit that can be added to the capacity score. Projects that will resolve capacity problems on multiple elements should use this process for each overloaded element and sum the results. The basic equation for all capacity or capacity/reliability projects is as follows:

EAR(Total) = EAR (N-0) + EAR (N-1) + EAR (N-2) + EAR Benefit (Improved Reliability)

1. EAR (N-0) Calculation

- Required information:
  - Normal rating
  - Expected peak load[1]
  - Operating company – BECo, Com or CELCo

  [1] Large projects (requiring over a year to plan and execute) should submit a peak load forecast extending out 2 – 3 years.

- Computations:
  - Subtract the normal rating from the expected peak load. This will give you the amount of overload in kVA. If the answer is less than or equal to 0, there is no load at risk, and the EAR(N-0) is 0.
  - Divide the normal rating by the expected peak, which will result in a number less than 1 if there is load at risk.
  - Use the load duration calculator to find the hours at risk and the load curve multiplier.
  - Multiply the amount of overload by the hours at risk and the load curve multiplier to compute EAR(N-0).

- Example:

  Assume that a project will resolve capacity problems on both a line and a transformer in NSTAR North. First calculate the EAR (N-0) for the line.

Capacity Constrained Line

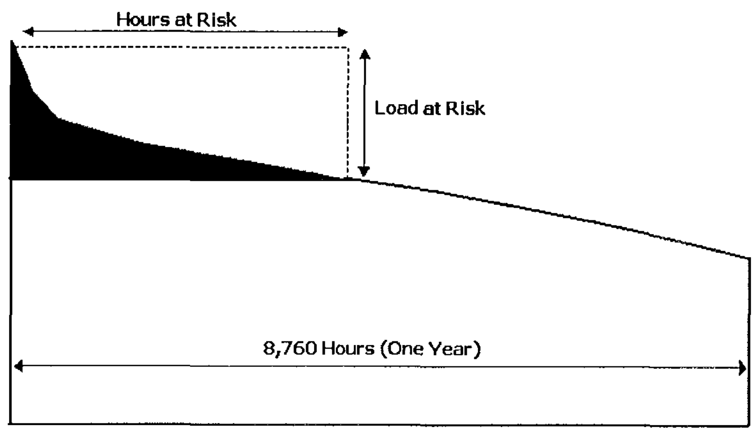
- Normal rating is 300 kVA
- Expected peak load is 327 kVA
- Amount of overload is (327 - 300), or 27 kVA, confirming load at risk
- Divide 300 kVA by 327 kVA; the answer is .917
- Using the load duration curve calculator, enter in .917 to find the hours at risk and the load curve multiplier. They are 72.5 hours and 0.42, respectively
- EAR(N-0) = 27 kVA x 72.5 hours x .42 = 822.2 kVAh

Capacity Constrained Transformer

- Normal rating is 5,000 kVA
- Expected peak load is 5,123 kVA
- Amount of overload is (5,123 - 5,000) or 123 kVA, confirming load at risk
- Divide 5,000 kVA by 5,123 kVA; the answer is .976
- Using the load duration curve calculator, enter in .976 to find the hours at risk and the load curve multiplier. They are 11.1 hours and 0.48, respectively
- EAR(N-0) = 123 kVA x 11.1 hours x .48 = 655.3 kVAh

This one project, since it will resolve two capacity problems, will have an EAR(N-0) score equal to the sum of the individual EAR(N-0) answers, or 655.3+822.2 = 1,477.5 kVAh.

The shaded area in the picture below is a representation of the energy at risk. If one multiplies the hours at risk by the load at risk, the result is the area inside the box. Since the only area of interest is the shaded area inside the box, the load curve multiplier is used to calculate what portion falls beneath the curve. Each operating company has its own load curve, so the hours at risk and load curve multiplier will normally be somewhat different for any given load at risk.



Pictorial representation of energy at risk

2. EAR (N-1) Calculation

- Required information:
  - List containing each element, that if lost, that will result in loss of load(1)
  - Long-term emergency rating of each of the above elements
  - If the element is a line, indicate the length of the segment whose failure would result in a first contingency condition
  - Condition of each element described above, if known
  - Resulting amount of load lost for each element described above – or the amount of load that must be shed to avoid exceeding the long term ratings of any piece of equipment
  - Amount of time needed to restore power to the majority of customers for each element described above
  - The amount of time needed to repair or replace the equipment, thus returning to an N-0 situation. The equipment repair time is convenient to collect at this time, but will only be used to calculate the EAR(N-2).

(1)If customers all retain power during a first contingency condition, there is no score for EAR(N-1) -- proceed directly to EAR(N-2) calculation.

This information might best be submitted in a tabular form, as shown below. If a DSS line group, as opposed to a single DSS line, is capacity constrained, the table below should be completed for each line in the line group. When possible, circuits and DSS line or line group projects should be accompanied by actual failure data in order to more accurately determine the likelihood of a first contingency event

Elements that will cause loss of load in first contingency situation							
Element	Condition	Length	Load Lost	Time to Restore Power	Time to Repair Equipment	Historical Failure Rate	LTE Rating
Transformer A	Fair	N/A	4 MVA	8 hours	36 hours	N/A	38 MVA
Transformer B	Fair	N/A	3 MVA	2 hours	36 hours	N/A	16 MVA
UG Transmission	Good	3.2 miles	40 kVA	3 hours	48 hours	N/A	128 MVA
DSS Line	Poor	4.1 miles	4 kVA	2 hours	24 hours	.02 failures per mile per year	3.5 MVA

Computations – Begin a similar table using the elements that will cause loss of load in a first contingency situation. The table consists of an evaluation of what may happen under peak loads if any one of the four key elements failed. Highlighted cells indicate elements that have exceeded their long-term emergency ratings for that particular scenario. For instance, if Transformer B fails, Transformer A will exceed its LTE rating by 4 MVA (42 MVA – 38 MVA), the underground transmission line will remain within its LTE rating, and the DSS line will exceed its LTE rating by 0.3 MVA (3.8 MVA – 3.5 MVA).

Failure of this: / Results in this:	Transformer A	Transformer B	UG Transmission	DSS Line
Transformer A	N/A	Load = 24 MVA LTE Rating = 19 MVA	Load = 120 MVA LTE Rating = 128 MVA	Load = 4 MVA LTE Rating = 3.5 MVA
Transformer B	Load = 42 MVA LTE Rating = 38 MVA	N/A	Load = 115 MVA LTE Rating = 128 MVA	Load = 3.8 MVA LTE Rating = 3.5 MVA
UG Transmission	Load = 42 MVA LTE Rating = 38 MVA	Load = 0 MVA LTE Rating = 19 MVA	N/A	Load = 5 MVA LTE Rating = 3.5 MVA
DSS Line	Load = 38 MVA LTE Rating = 38 MVA	Load = 22 MVA LTE Rating = 19 MVA	Load = 115 MVA LTE Rating = 128 MVA	N/A

For each yellow cell, divide the LTE rating by the load to obtain a value that will be entered into the load duration calculator. For simplicity, enter the results (hours at risk and load curve multiplier, LCM) into a form such as the one shown below:

Failure of this: / Results in this:	Transformer A	Transformer B	UG Transmission	DSS Line
Transformer A	N/A	0.791 Hours at Risk: 461 LCM: .31	N/A	0.875 Hours at Risk: 135 LCM: .38
Transformer B	0.904 Hours at Risk: 87 LCM: .42	N/A	N/A	0.921 Hours at Risk: 68 LCM: .42
UG Transmission	0.904 Hours at Risk: 87 LCM: .42	N/A	N/A	0.700 Hours at Risk: 1,648 LCM: .23
DSS Line	N/A	0.864 Hours at Risk: 173 LCM: .37	N/A	N/A

Now calculate the EAR for each element that may cause loss of load. Work across the rows, using the basic formula as follows:

$EAR(N\text{-}1)_{\text{Element } i} =$

$$\left[\sum_{\substack{\text{Remaining}\\ \text{Elements}}}\left(\frac{\text{Hours at Risk}}{8{,}760\,\text{Hours}} \times \text{Load at Risk} \times \text{Hours to Restore Power} \times \text{LCM}\right)\right] \times L\{\text{Failure}\}_{\text{Element } i}$$

- The load at risk is that which must be shed to avoid exceeding the long-term emergency ratings of any piece of equipment
- The notation L{Failure} is the likelihood of failure during a given year, and is derived from either industry or NSTAR failure rates. In the case of Transformers A and B, the failure rate is 0.011. For the transmission line, the estimated system wide NSTAR failure rate for underground lines is used - 0.0305 failures per mile per year - which amounts to 0.0976 failures per year for this particular segment. The actual DSS line failure rate is provided and used in the calculation.

For example, the EAR(N-1) calculations are as follows:

$$EAR(N\text{-}1)_{\text{Transformer A}} = \left[\left(\frac{461\text{ Hours}}{8{,}760\text{ Hours}} \times 5{,}000\text{ kVA} \times 8\text{ Hours} \times 0.31\right) + \left(\frac{135\text{ Hours}}{8{,}760\text{ Hours}} \times 500\text{ kVA} \times 8\text{ Hours} \times 0.38\right)\right] \times 0.011$$

= (652.6 kVAh + 23.4 kVAh) x 0.011 = **7.4 kVAh**

$$EAR(N\text{-}1)_{\text{Transformer B}} = \left[\left(\frac{87\text{ Hours}}{8{,}760\text{ Hours}} \times 4{,}000\text{ kVA} \times 2\text{ Hours} \times 0.42\right) + \left(\frac{68\text{ Hours}}{8{,}760\text{ Hours}} \times 300\text{ kVA} \times 2\text{ Hours} \times 0.42\right)\right] \times 0.011$$

=(33.4 kVAh 2.0 kVAh) x 0.011 = **0.4 kVAh**

$$EAR(N\text{-}1)_{\text{Transmission Line}} = \left[\left(\frac{87\text{ Hours}}{8{,}760\text{ Hours}} \times 4{,}000\text{ kVA} \times 3\text{ Hours} \times 0.42\right) + \left(\frac{1{,}648\text{ Hours}}{8{,}760\text{ Hours}} \times 1{,}500\text{ kVA} \times 3\text{ Hours} \times 0.23\right)\right] \times 0.0976$$

=(50.1 kVAh + 194.7 kVAh) x 0.0976 = **23.9 kVAh**

$$EAR(N\text{-}1)_{\text{DSS Line}} = \left[\left(\frac{173\text{ Hours}}{8{,}760\text{ Hours}} \times 5{,}000\text{ kVA} \times 2\text{ Hours} \times 0.37\right)\right] \times 0.082$$

= (73.1 kVAh) x 0.082 = **6.0 kVAh**

When the EAR(N-1) is calculated for each element (both transformers, the transmission line and the DSS line), the results can be summed to create an EAR for a capacity project, such as a new substation, that will resolve multiple capacity problems.

$$EAR(N\text{-}1)_{Total} = 7.4 + 0.4 + 23.9 + 6.0 = \underline{37.7\ kVAh}$$

3. EAR (N-2) Calculation

Using the information that was gathered to calculate the EAR(N-1), form a table similar to the one shown below. For the purposes of this illustration, assume that the transmission line has failed, and since it supplied Transformer B, that is deenergized as well. Although it is likely that more elements may come into play (and thus create additional columns that were not needed for the N-1 calculation), this example assumes no additional pieces of equipment are overloaded for purposes of simplicity.

The question this chart will answer is this: Given that the transmission line is out, and therefore Transformer B is deenergized, what is the magnitude and duration of load shedding that must take place should either Transformer A or the DSS Line fail?

Failure of this: \ Results in this:	Transformer A	Transformer B	UG Transmission	DSS Line
Transformer A	N/A	Fed by UG Transmission - deenergized	Faulted	Load = 38 MVA LTE Rating = 3.5 MVA
Transformer B	Fed by UG Transmission - deenergized	Fed by UG Transmission - deenergized	Faulted	Fed by UG Transmission - deenergized
UG Transmission	Faulted	Faulted	Faulted	Faulted
DSS Line	Load = 45 MVA LTE Rating = 38 MVA	Fed by UG Transmission - deenergized	Faulted	N/A

To answer this, the load duration calculator is again used, in the exact same manner as before, to calculate the hours at risk and the load curve multiplier. In most (but not all) N-2 situations, the hours at risk are 8,760.

Failure of this: \ Results in this:	Transformer A	Transformer B	UG Transmission	DSS Line
Transformer A	N/A	Fed by UG Transmission - deenergized	Faulted	0.092 Hours at Risk: 8,760 LCM: .42
Transformer B	Fed by UG Transmission - deenergized	Fed by UG Transmission - deenergized	Faulted	Fed by UG Transmission - deenergized
UG Transmission	Faulted	Faulted	Faulted	Faulted
DSS Line	0.679 Hours at Risk: 2,103 LCM: .23	Fed by UG Transmission - deenergized	Faulted	N/A

The next step is to determine the amount of time the system at hand is likely to spend in a first contingency condition (since that is a prerequisite to the existence of a second contingency situation). This is found by examination of the time to repair the equipment after an event and the likelihood of an event in the first place. Using equations, this is expressed as:

$$\text{Exposure to (N-2)} = \sum(\text{Yearly expected failure rate of unit}) \times (\text{equipment restoral time})$$

Exposure to an N-2 condition must be combined with the likelihood of a subsequent failure in order to determine the likelihood of an N-2 event. In this example, only the DSS line and Transformer A are left. If enough load was dropped so that both the transformer and DSS line are kept below their LTE ratings (thus not increasing failure probability), the likelihood of subsequent failure is as follows:

$$\text{L(N-2)} = (\text{Exposure to N-2}) \times \sum \text{failure rates of remaining equipment}$$

In the example above, the likelihood of an N-2 is calculated below using generic or NSTAR failure rates for the transmission line, transformers and DSS line. This likelihood is actually a conservative estimate on the high side, given that one cannot predict which piece of equipment will fail to produce the N-1.

L(N-2) =

$$\left(\frac{.011\,\text{failures}}{8760\,\text{hrs}} \times 36\,\text{hrs}\right) + \left(\frac{.011\,\text{failures}}{8760\,\text{hrs}} \times 36\,\text{hrs}\right) + \left(\frac{.0305\,\text{failures}}{\text{mile} \times 8760\,\text{hrs}} \times 3.2\,\text{miles} \times 48\,\text{hrs}\right)$$
$$+ \left(\frac{.02\,\text{failures}}{\text{mile} \times 8760\,\text{hrs}} \times 4.1\,\text{miles} \times 24\,\text{hrs}\right) = .00085\,\text{failures expected}$$

The next calculation is the EAR(N-2), which factors in the likelihood of an N-2 situation, the amount of load loss that potentially could occur, and the duration of the resulting outage. The duration of the N-2 condition is determined by the longest repair time in any of the N-1 scenarios, or an estimate of the amount of time required to restore power to the majority of customers. If the load lost during an N-2 situation were 100 MVA, for example, the EAR_{N-2} calculation would be as follows:

EAR(N-2)= 100 MVA x .00085 x 48 hours = 4,080 kVAh

The total EAR for our example is:

Total EAR = EAR(N-0) + EAR(N-1) + EAR(N-2)

0.0 kVAh + 37.7 kVAh + 4,080 kVAh = **4,117.7 kVAh**

If the project will mitigate all of the capacity concerns, thus reducing the risk to an insignificant level, the EAR benefit is equal to the total EAR. This is generally the case for all substation and transmission capacity projects, and many of the distribution projects.

Network Projects

The purpose of this section is to document how the EAR was calculated for network projects in the absence of a load flow program. System Planning is currently acquiring a program to model meshed networks, and therefore future EAR calculations of network projects will more accurately reflect the expected energy at risk.

The network is comprised of twelve grids that are fed from six bulk substations. The following chart is an approximation of how much load each sub-grid carries, assuming the load is equally distributed throughout the network. The 2004 projected sub-grid load is calculated by multiplying columns three and four in the table below:

Station	Grid	2004 Projected Station Load	Sub-grid Load as a % of Station Load	2004 Projected Sub-Grid Load
Hawkins St #2	2	69,920 kVA	76%	53,139 kVA
Chatham St #12	12 N	108,640 kVA	37%	40,197 kVA
Chatham St #12	12 S	108,640 kVA	36%	39,110 kVA
Chatham St #12	12 W	108,640 kVA	24%	26,074 kVA
High St #53	53 E	108,000 kVA	57%	61,560 kVA
High St #53	53 S	108,000 kVA	25%	27,000 kVA
High St #53	53 W	108,000 kVA	18%	19,440 kVA
Carver St #71	71	83,000 kVA	100%	83,000 kVA
Scotia St #492	492 N	126,650 kVA	36%	45,594 kVA
Scotia St #492	492 S	126,650 kVA	49%	62,059 kVA
Kingston St #514	514 N	139,000 kVA	62%	86,180 kVA
Kingston St #514	514 S	139,000 kVA	38%	52,820 kVA

The information regarding the network loading was scarce, since individual feeder outages do not result in a loss of power to the customer. The primary input into this calculation was the percent of loading for each feeder under normal conditions (known) and the percent of overloading that would occur under a first contingency condition (estimated). Of the 2004 network projects that were submitted, only two were expected to overload under a first contingency condition, and the magnitude of the overload was estimated at 20%. Therefore, the likelihood of subsequent failure (N-2 condition) for these two elements was arbitrarily multiplied by twenty.

System Engineering also estimated feeder outages hours that are likely to occur in a year as 1,000 hours. If we distribute these hours equally among the primary grids, then the amount of exposure to an N-2 condition can be estimated by dividing by 8,760 hours.

The chart below depicts the estimated outage hours per primary grid and the associated N-2 exposure.

Station	Percent of Primary Grid Load	Expected Annual Grid Outage Hours	Associated N-2 Exposure
Hawkins St #2	11.0%	110.1	.013
Chatham St #12	17.1%	171.0	.020
High St #53	17.0%	170.0	.019
Carver St #71	13.1%	130.7	.015
Scotia St #492	19.9%	199.4	.023
Kingston St #514	21.9%	218.8	.025

To calculate the EAR for the network capacity projects, a gross assumption is made that an N-2 condition will result in the loss of one of the twelve sub-grids for approximately 72 hours. Again, this was done in the absence of a load flow model, and should be verified when accurate information is available. Another assumption used is the probability of a random feeder outage occurring in the area to produce the N-2 condition. This is estimated as 1/20, due to lack of detailed records on the actual feeder failure rate.

The likelihood of an N-2 condition is calculated using the equation below, with the loading element added to give weight to projects involving feeders closer to their normal ratings.

L(N-2) = (N-2 Exposure) x (1/20) x (% load of normal rating) x
(amount feeder overloads under N-1 condition, if applicable)

The EAR (Total) is equal to the EAR (N-2) for network feeders, and is represented by the following equation:

EAR (Total) = L(N-2) x (72 hours) x (Sub-grid load in kVA)

Reliability Projects

Substation Technical Engineering, Distribution Engineering, Transmission and System Engineering generally submit reliability projects. Examples of reliability projects include:

- DSS line repair or rebuild
- Circuit inspection and repair
- Circuit rebuild or replacement
- 4 kV conversions
- Removal of double circuit tower conditions
- Transformer restoration
- Old and obsolete breaker replacement

For single DSS line and distribution circuit reliability projects, the EAR is calculated based on actual data. This data includes the peak load on the line or circuit, the estimated number of customers on the line or circuit, and the 12-month rolling COH (customer outage hours). Using the peak load and the number of customers, we can estimate the average maximum usage per customer using the following formula:

$$\text{Avg. Load}_{\text{Customer}} = \text{Average Circuit Load} \div \text{Number of Customers on Circuit}$$

The average load on the circuit is calculated by taking the actual peak load on the circuit and multiplying it a factor derived from either the Boston Edison, Commonwealth Electric or Cambridge Electric load duration curve. These factors are as follows:

Boston Edison average load = 60% of peak load
Cambridge Electric average load = 49% of peak load
Commonwealth Electric average load = 46% of peak load

The expected energy at risk in this case is the amount of time the customers are likely to be without power during the next year. It is calculated using the following formula:

$$\text{EAR} = \text{Avg. Load}_{\text{Customer}} \times \text{Rolling COH}$$

The EAR benefit is computed by estimating the decrease in COH based on the type and amount of work that is planned. For example, rebuilding a URD area will decrease the COH by near 100%, but repairing a line's trouble spots is expected to decrease the COH by only 20%. The EAR benefit for these reliability projects is calculated using the following formula:

$$\text{EAR Benefit} = \text{Ave. Load}_{\text{Customer}} \times \text{Expected COH decrease}$$

DSS lines that are part of a line group are treated somewhat differently, since their failure may result in a second contingency condition, particularly if the other lines in the group are deemed to be in poor or marginal condition. This second contingency condition is assumed to be loss of the line group, for simplicity. This assumption is conservative, though not unrealistic.

For other types of reliability projects, one must estimate maximum load loss upon failure of the element or elements to be replaced. Using NSTAR records or industry failure data, the probability of occurrence is approximated, as well as the increase in reliability (or decrease in outage duration) that will occur as a result of completing the project. The EAR is then calculated by the following formulas:

$$\text{EAR(Total)} = \text{EAR(N-1)} + \text{EAR(N-2)}$$

$$\text{EAR(N-1)} = \text{Probable loss of load upon malfunction x Likelihood of malfunction}$$

$$\text{EAR(N-2)} = \frac{\text{Hours to Restore Equipment}}{\text{8,760 Hours}} \text{ x Probable loss of load x Likelihood of N-2}$$

The EAR benefit is an approximation of how much value the project will provide by either decreasing the failure rate or decreasing the amount of time required to restore customers after an event.

$$\text{EAR Benefit} = \text{EAR(Total) x \% Decrease in Failure Rate}$$

<u>or</u>

$$\text{EAR Benefit} = \text{EAR(Total) x \% Decrease in Restoral Time}$$

Should the project result in both a decrease in failure rate and restoral time, the appropriate equation is shown below:

$$\text{EAR Benefit} = \left[\text{EAR(Total) x \% Decrease in Failure Rate}\right] + \left[\text{EAR(Total) x \% Decrease in Restoral Time x \% Decrease in Failure Rate}\right]$$

APPENDIX

Failure Rates

Transmission Lines:

The probability of failure for a given overhead transmission line is determined by the following equation based on Remvec and NSTAR data:

P{Failure} = 0.0305 failures x length of circuit (in miles)

The probability of failure for a given underground transmission line is determined by the following equation based on Remvec and NSTAR data:

P{Failure} = 0.0075 failures x length of circuit (in miles)

An approximate probability of failure for any transmission line can be obtained by the above failure rates and the NSTAR overhead to underground ratio:

P{Failure} = 0.0254 failures x length of circuit (in miles)

Transformers:

The probability of any transmission transformer failing during a given year, based on both industry averages and NSTAR data, is 0.011.

The probability of any distribution transformer failing during a given year, based on data collected by ABB, is 0.020.

If a transmission transformer is known to be in poor condition and is therefore considered to be a greater reliability risk, this probability is increased to 0.110.

If a distribution transformer is known to be in poor condition and is therefore considered to be a greater reliability risk, this probability is increased to 0.200.

DSS Lines:

The probability of any DSS line failing during a given year is taken from ABB's data on cable primary failures, since generic DSS data was unavailable.

P{Failure} = 0.030 failures x length of circuit (in miles)

If the DSS line is known to be in poor condition AND the actual failure data is not available, this probability is increased.

P{Failure} = 0.150 failures x length of circuit (in miles)

APPENDIX

Underground Cable:

The probability of any underground cable failing during a given year is taken from ABB's data on cable primary and secondary failures.

P{Failure} = 0.030 failures x length of circuit (in miles) for the primary
and
P{Failure} = 0.110 failures x length of circuit (in miles) for the secondary

If the underground cable is known to be in poor condition AND the actual failure data is not available, this probability is increased.

P{Failure} = 0.150 failures x length of circuit (in miles) for the primary
and
P{Failure} = 0.550 failures x length of circuit (in miles) for the secondary

Overhead Lines:

The probability of any overhead line failing during a given year is taken from ABB's data on overhead line failures.

P{Failure} = 0.200 failures x length of circuit (in miles)

If the line is known to be in poor condition or runs through a heavily treed area, AND the actual failure data is not available, this probability is increased.

P{Failure} = 1.000 failures x length of circuit (in miles)

Circuit Breakers and Busses:

The probability of any circuit breaker failing during a given year, taken from ABB's data on circuit breaker failures, is 0.0066.

The probability of any bus failing during a given year, taken from ABB's data on bus failures, is .2200.

UTT Tap Changers:

P{Failure} = 0.023 failures per LTC years of operation (NSTAR experience)

U-Bushings:

P{Failure} = 0.002 failures per bushing year of operation (NSTAR experience)

APPENDIX

Load Duration Curves

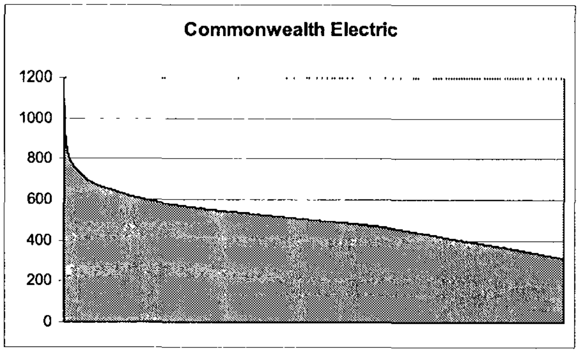
Capability / Expected Load	Commonwealth Load Curve Multiplier	Commonwealth Hours at Risk	Cambridge Load Curve Multiplier	Cambridge Hours at Risk	Boston Edison Load Curve Multiplier	Boston Edison Hours at Risk
100%	0.50	0	0.50	0	0.50	0
99%	0.53	4	0.49	2	0.44	7
98%	0.56	7	0.49	3	0.46	10
97%	0.57	9	0.42	7	0.45	18
96%	0.48	15	0.26	18	0.45	26
95%	0.47	19	0.29	31	0.45	34
94%	0.50	22	0.29	48	0.44	44
94%	0.52	22	0.33	61	0.43	56
92%	0.57	24	0.36	71	0.41	69
91%	0.61	25	0.39	79	0.43	79
90%	0.64	25	0.41	89	0.41	96
89%	0.65	26	0.42	99	0.38	117
89%	0.65	27	0.45	105	0.39	135
88%	0.66	28	0.48	110	0.38	155
86%	0.67	29	0.48	118	0.37	181
86%	0.67	29	0.49	124	0.36	209
84%	0.68	30	0.50	129	0.36	237
83%	0.63	34	0.51	135	0.36	262
82%	0.60	36	0.52	139	0.34	303
81%	0.59	39	0.53	144	0.33	348
80%	0.55	43	0.53	150	0.32	407
79%	0.51	49	0.53	156	0.31	468
78%	0.49	52	0.54	160	0.30	532
77%	0.49	55	0.55	165	0.29	606
76%	0.44	64	0.53	177	0.29	687
75%	0.42	73	0.52	187	0.28	793
74%	0.38	84	0.51	198	0.27	908
73%	0.34	99	0.50	210	0.26	1042
72%	0.32	114	0.46	235	0.25	1209
71%	0.29	139	0.44	259	0.23	1441
70%	0.26	166	0.40	296	0.23	1647
69%	0.25	195	0.39	324	0.23	1860
68%	0.23	236	0.38	346	0.23	2076
67%	0.22	272	0.37	374	0.23	2299
66%	0.22	302	0.35	414	0.23	2552
65%	0.21	348	0.32	479	0.22	2852
64%	0.21	392	0.31	534	0.22	3194
63%	0.20	445	0.29	594	0.22	3542
62%	0.19	523	0.28	663	0.22	3835
61%	0.18	623	0.27	748	0.23	4100
60%	0.17	733	0.26	836	0.23	4347
59%	0.17	847	0.25	940	0.24	4580
58%	0.17	967	0.23	1068	0.25	4828
57%	0.17	1088	0.22	1230	0.25	5067

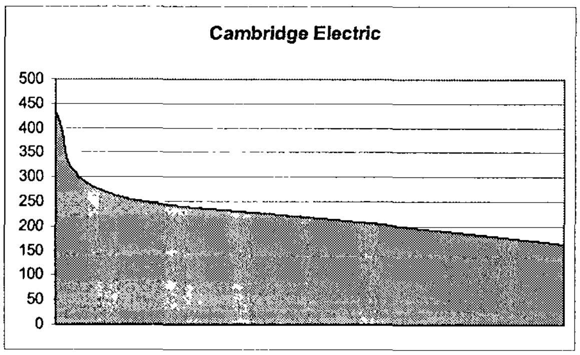
APPENDIX

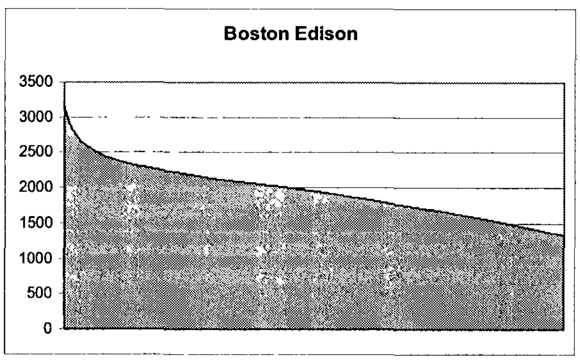
Capability / Expected Load	Commonwealth Load Curve Multiplier	Commonwealth Hours at Risk	Cambridge Load Curve Multiplier	Cambridge Hours at Risk	Boston Edison Load Curve Multiplier	Boston Edison Hours at Risk
56%	0.17	1230	0.21	1429	0.26	5282
55%	0.16	1414	0.19	1698	0.26	5511
54%	0.16	1594	0.18	1998	0.27	5762
53%	0.16	1820	0.17	2375	0.27	5996
52%	0.15	2080	0.16	2810	0.28	6237
51%	0.15	2403	0.15	3230	0.28	6445
50%	0.15	2744	0.15	3639	0.29	6651
49%	0.15	3117	0.15	4042	0.29	6841
48%	0.15	3488	0.15	4426	0.30	7052
47%	0.15	3873	0.16	4790	0.30	7267
46%	0.15	4280	0.16	5140	0.31	7450
45%	0.15	4722	0.17	5443	0.31	7619
44%	0.15	5102	0.17	5740	0.32	7787
43%	0.16	5432	0.18	6082	0.32	7961
42%	0.16	5717	0.18	6415	0.33	8152
41%	0.17	5953	0.19	6768	0.33	8324
40%	0.18	6176	0.19	7095	0.34	8494
39%	0.19	6396	0.20	7399	0.34	8619
38%	0.19	6612	0.20	7712	0.33	8688
37%	0.20	6828	0.21	7997	0.34	8722
36%	0.21	7061	0.21	8231	0.34	8733
35%	0.21	7285	0.22	8431	0.35	8750
34%	0.22	7525	0.23	8597	0.35	8759
33%	0.22	7744	0.24	8680	0.36	8760
32%	0.23	7952	0.25	8688	0.36	8760
31%	0.23	8163	0.26	8692	0.36	8760
30%	0.24	8382	0.27	8698	0.36	8760
29%	0.24	8583	0.28	8705	0.36	8760
28%	0.32	8723	0.29	8710	0.36	8760
27%	0.38	8754	0.30	8720	0.36	8760
26%	0.40	8760	0.31	8732	0.36	8760
25%	0.41	8760	0.32	8741	0.36	8760
24%	0.42	8760	0.33	8755	0.36	8760
23%	0.43	8760	0.33	8760	0.37	8760
22%	0.44	8760	0.34	8760	0.37	8760
21%	0.45	8760	0.35	8760	0.37	8760
20%	0.46	8760	0.36	8760	0.37	8760
19%	0.48	8760	0.37	8760	0.38	8760
18%	0.49	8760	0.38	8760	0.38	8760
17%	0.50	8760	0.38	8760	0.38	8760
16%	0.51	8760	0.39	8760	0.38	8760
15%	0.53	8760	0.40	8760	0.39	8760
14%	0.56	8760	0.41	8760	0.38	8760
13%	0.59	8760	0.41	8760	0.40	8760
12%	0.60	8760	0.42	8760	0.40	8760
11%	0.64	8760	0.43	8760	0.41	8760

APPENDIX

Capability / Expected Load	Commonwealth Load Curve Multiplier	Commonwealth Hours at Risk	Cambridge Load Curve Multiplier	Cambridge Hours at Risk	Boston Edison Load Curve Multiplier	Boston Edison Hours at Risk
10%	0.69	8760	0.43	8760	0.42	8760
9%	0.66	8760	0.44	8760	0.42	8760
8%	0.60	8760	0.44	8760	0.41	8760
7%	0.50	8760	0.45	8760	0.43	8760
6%	0.48	8760	0.46	8760	0.43	8760
5%	0.49	8760	0.46	8760	0.44	8760
4%	0.49	8760	0.47	8760	0.45	8760
3%	0.56	8760	0.47	8760	0.44	8760
2%	0.56	8760	0.48	8760	0.46	8760
1%	0.48	8760	0.48	8760	0.50	8760
0%	0.56	8760	0.49	8760	0.47	8760







APPENDIX

Growth Rates

The growth rates shown below are based on the ABB Forecast that was developed in 2001.

AREA	YTD Peak - 2004	2004 - 2005
Hawkins Street #2	6.10%	1.09%
Chatham Street #12	10.22%	0.89%
High Street #53	12.07%	0.93%
Carver Street #71	6.08%	1.20%
Scotia Street #492	2.46%	2.01%
Kingston Street #514	6.05%	0.72%
L Street #4	-45.58%	0.00%
New K Street # 385D	N/A	7.78%
Andrew Square #106	-2.82%	0.75%
Baker Street #110	1.88%	0.00%
Brighton #329	4.77%	6.42%
Dewar Street #483	1.11%	1.45%
Hyde Park #496	3.87%	2.99%
Mystic #250	1.39%	0.54%
Somerville #402	2.70%	1.28%
Chelsea #488	10.26%	2.13%
Woburn #211	1.09%	0.71%
North Woburn #375	4.44%	3.06%
Burlington #391	6.19%	0.00%
Lexington #320	6.25%	1.39%
Hartwell Avenue #533	1.10%	0.00%
Waltham #282	5.60%	0.72%
Trapelo Road # 450	1.85%	1.19%
Needham #148	3.21%	1.20%
Newton #292	-1.16%	1.19%
Watertown #467	4.33%	0.00%
Walpole #146	6.79%	0.00%
Dover #456	10.00%	0.00%
Canton #470	0.00%	0.00%
Sudbury #342	1.28%	2.50%
Maynard #416	1.25%	-1.22%
Speen Street #433	8.48%	0.76%
Leland Street #240	0.00%	1.37%
Sherborn #274	0.98%	1.92%
West Framingham #455	4.55%	0.00%
Medway #65	0.98%	1.92%
Hopkinton #126	2.27%	13.04%
Kendall #800	22.28%	7.53%
Prospect #819	2.70%	1.28%
Alewife #828	6.63%	0.00%
Putnam #831	1.80%	4.35%
New Bedford District	1.01%	1.01%
Plymouth District	1.01%	1.01%
Cape and Vineyard District	1.02%	1.02%